Basin Margin Dakota Oil Play

(USGS Designation 2206)

General Characteristics

The Basin Margin Dakota Oil Play is both a structural and stratigraphic play on the northern, southern, and western sides of the central San Juan Basin, and the southeastern part of the Ute Mountain Ute Indian Reservation (Figs. UM-41 and UM-42). Because of the variability of depositional environments in the transgressive Dakota Sandstone, it is difficult to characterize a typical reservoir lithology. Most production has been from the upper marine part of the interval but significant amounts of both oil and gas also have been produced from the nonmarine section.

Reservoirs: The Late Cretaceous Dakota Sandstone varies from dominantly nonmarine channel deposits and interbedded coal and conglomerate in the northwest to dominantly shallow marine, commonly burrowed deposits in the southeast. Net pay thicknesses range from 10 to 100 ft; porosities are as high as 20% and permeabilities are as high as 400 mD.

Source rocks: Along the southern margin of the play, the Cretaceous marine Mancos Shale was the source of the Dakota oil. API gravities range from 44° to 59°. On the Four Corners Platform to the west, nonmarine source rocks of the Menefee Formation were identified as the source (Ross, 1980). The stratigraphically higher Menefee is brought into close proximity with the Dakota across the Hogback Monocline.

Timing and migration: Depending on location, the Dakota Sandstone and Lower Mancos Shale entered the oil window during the Oligocene to Miocene. In the southern part of the area, migration was still taking place in the late Miocene or even more recently.

Traps: Fields range in size from 40 to 10,000 acres and most production is from fields of 100-2,000 acres. Stratigraphic traps are typically formed by updip pinchout of porous sandstone into shale or coal. Structural traps on faulted anticlines sealed by shale form some of the larger fields in the play. Oil production ranges in depth from 1,000 to 3,000 feet.

Exploration status and resource potential: The first discoveries in the Dakota play were made in the early 1920's on small anticlinal structures on the Four Corners Platform. Approximately 30% of the oil fields have an estimated total production exceeding 1 MMBO, and the largest field (Price Gramps) has production of 7 MMBO. Future Dakota oil discoveries are likely as basin structure and Dakota depositional patterns are more fully understood.

Stratigraphy

The Dakota Sandstone is a coastal plain deposit laid down in front of the advancing Mancos Sea. In the Ute Mountain Ute Indian Reservation the lower Dakota consists primarily of ribbon-type fluvial sandstone bodies and the upper Dakota consists of carbonaceous paludal shales deposited in coastal-plain or deltaic environments. The Dakota unconformably overlies the fluvial deposits of the Burrow Canyon Formation (Fig. UM-43). This unconformity progressively truncates older units from northeast to southwest. The upper boundary is conformable with the Mancos Formation.

Reservoirs in the Basin Margin Dakota Oil Play are controlled by stratigraphic and structural trapping (Fig. UM-44). Successful exploration for lower Dakota Sandstone production is accomplished by careful mapping of channel sandstones and close attention to oil and gas shows in the thin porous sandstones that may develop into channels.

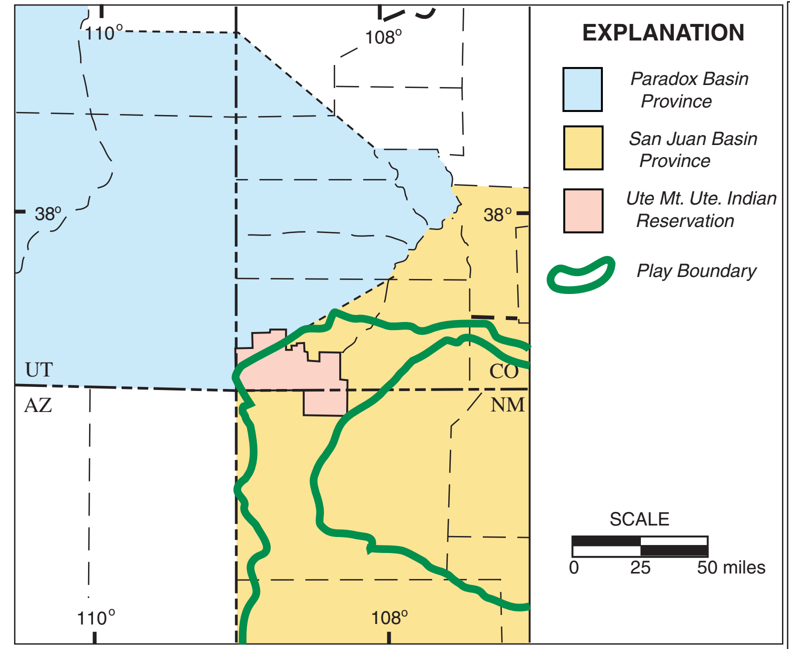


Figure UM-41. Location of Basin Margin Dakota Oil Play (modified after Gautier, et al., 1996).

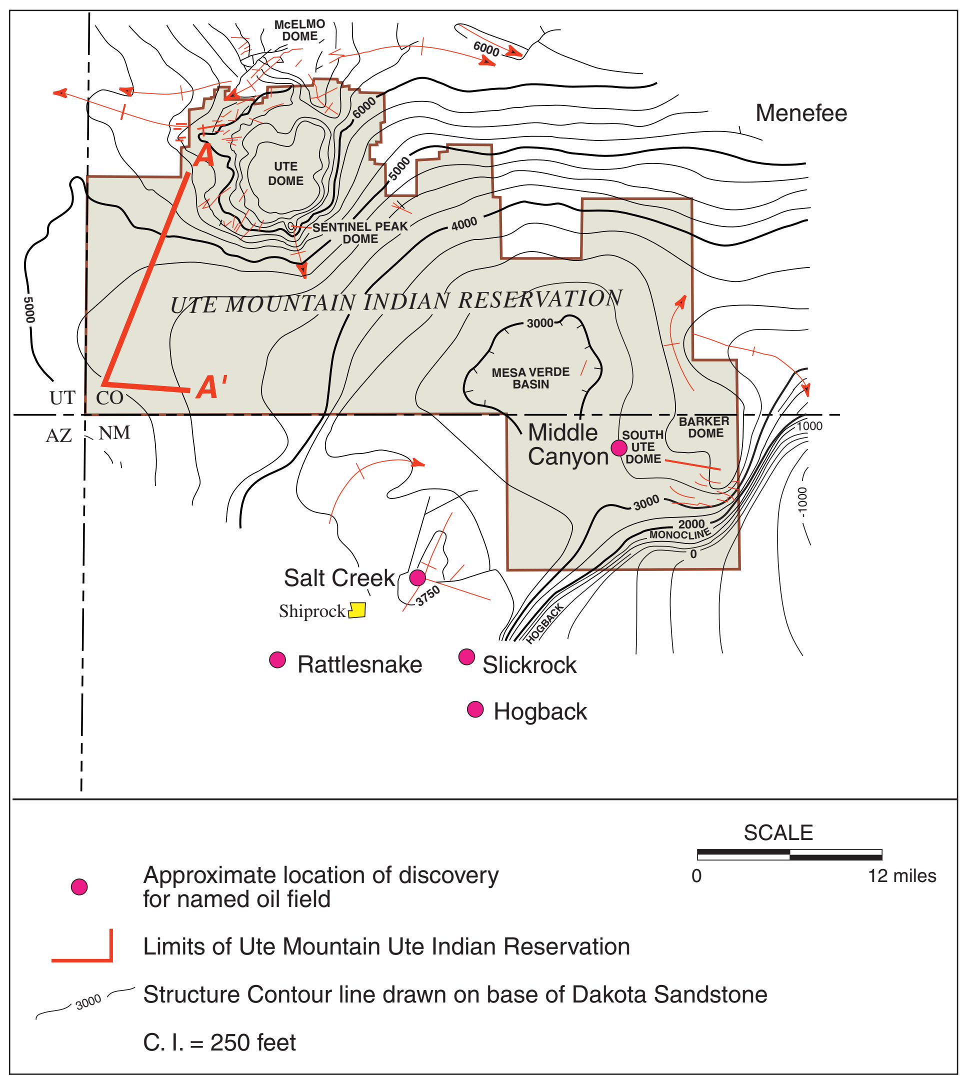


Figure UM-42. Structure contour map of the basal Dakota Sandstone and location of oil field discovery wells for fields producing from the Basin Margin Dakota Oil Play (modified after Anderson, 1995).

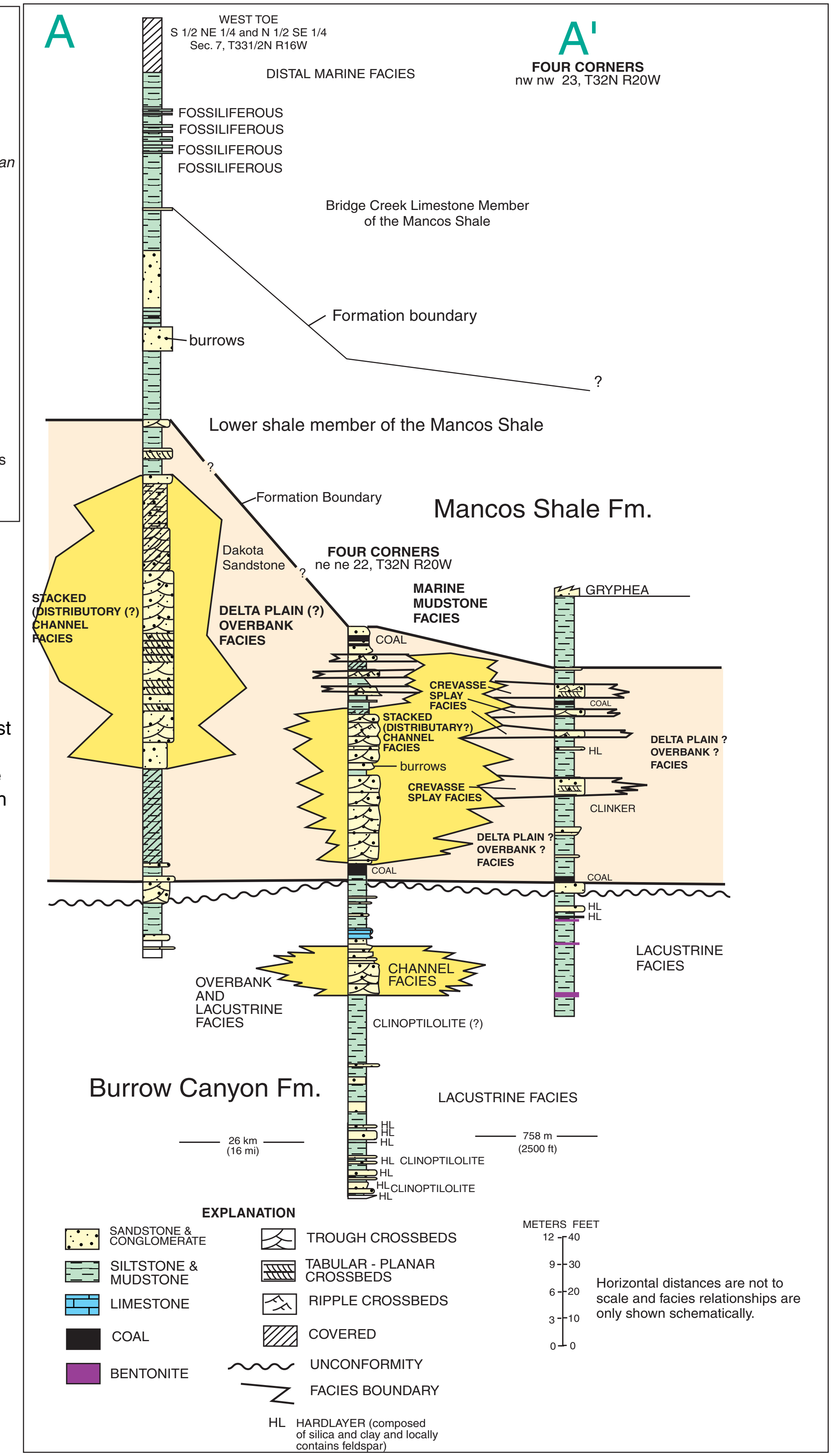


Figure UM-43. Correlation of uppermost Jurassic to Mid-Cretaceous rocks in the Ute Mountain Ute Indian Reservation (modified from Aubrey, 1992).

Analog Fields Inside or Near Reservation

(*) denotes field lies inside reservation boundaries

*Middle Canyon Dakota Field

(Fig. UM-44)

- Location of discovery well: NE ¼, SW ¼, sec. 14, T32N, R1 W (September 1969)
- Producing formation: Cretaceous Dakota Sandstone
- Number of producing wells: 1
- Production: 4,886 BO (1971)
- Type of drive: Water
- Average net pay: 20 feet
- Porosity: 12.1 %
- Permeability: 0.3 mD

Salt Creek Dakota Field

- Location of discovery well: SW ¼, NW ¼, Sec 4, T30N, R17W (July, 1958)
- Producing formation: Cretaceous Dakota Sandstone
- Number of producing wells: 6 (1977)
- Production: 88,604 BO (1977)
- Gas characteristics: 51.8 ° API Gravity
- Type of drive: Water
- Average net pay: 30 - 40 feet
- Porosity: 16 %
- Permeability: 0.8 mD.

Menefee Mountain Field

- Location of discovery well: NW ¼, NE ¼, Sec 16, T35N, R13W (July, 1978)
- Producing formation: Cretaceous Dakota Sandstone
- Number of producing wells: 3 (1981)
- Production: 33,356 BO (1981)
- Gas characteristics: 34 ° API Gravity
- Type of drive: Water
- Average net play: 15 feet
- Porosity: 12 - 14 %
- Permeability: Unknown

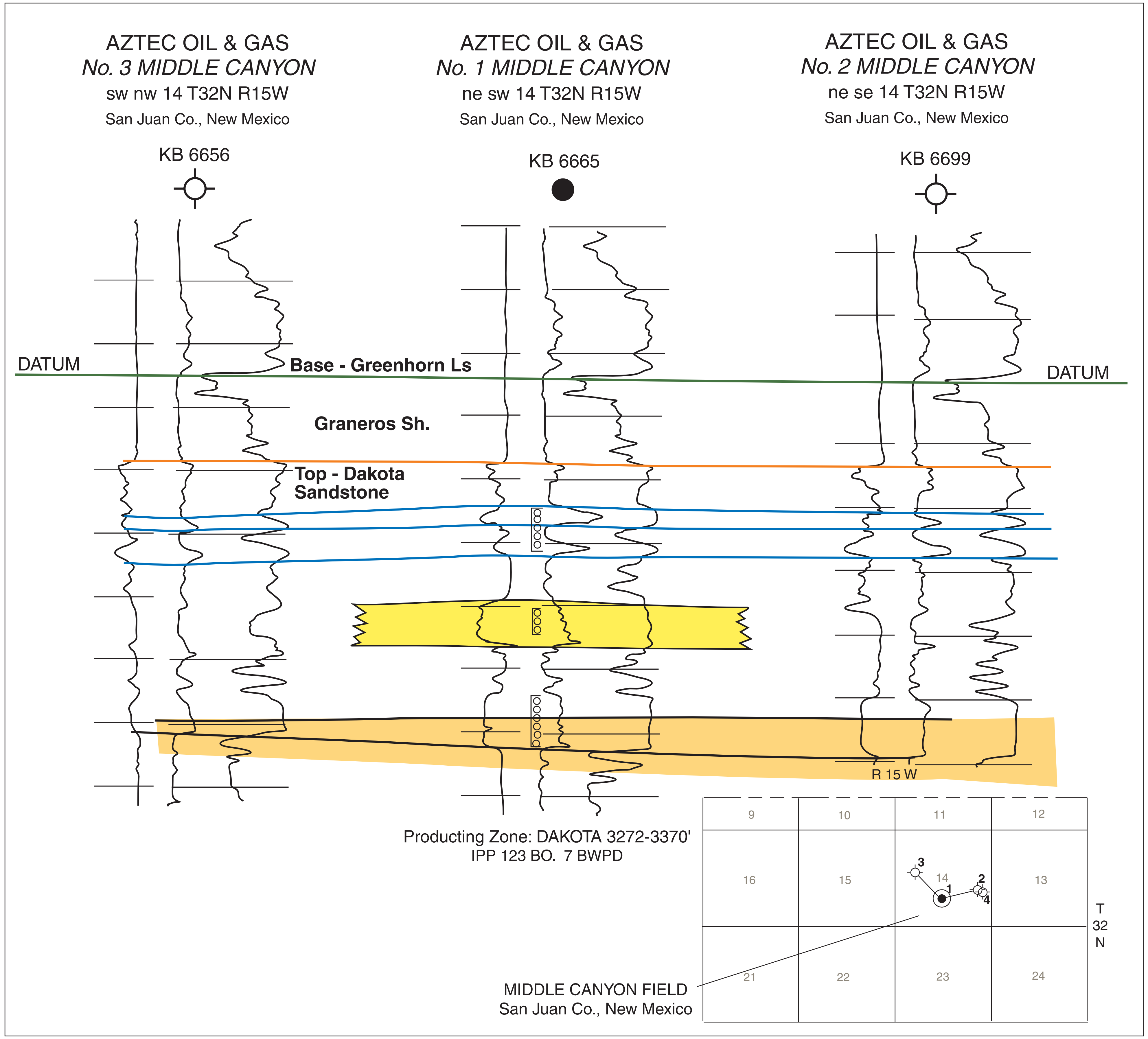


Figure UM-44. Cross section showing producing interval of the Dakota Sandstone in the Middle Canyon Field (modified after Stevensen, 1978).

DAKOTA CENTRAL BASIN GAS PLAY

(USGS Designation 2205)

GENERAL CHARACTERISTICS

This Dakota Central Basin unconventional continuous-type play is contained in coastal marine barrier-bar sandstone and continental fluvial sandstone units, primarily within the transgressive Dakota Sandstone. It is located in the northeastern part of the San Juan Basin province and the southeastern corner of the Ute Mountain Ute Indian Reservation (Figs. UM-45 to UM-47).

Reservoirs: Reservoir quality is highly variable. Most of the marine sandstone reservoirs within the central basin field are considered tight in that the porosities range from 5% to 15% and permeabilities range from 0.1 to 0.25 mD. Fracturing, both natural and induced, is essential for effective field development.

Source Rocks: Quality of the source beds for oil and gas is also variable. Non-associated gas in the Dakota pool was generated during the late mature and postmature stages and probably had a marine Mancos Shale source (Rice, 1983).

Timing and Migration: In the northern part of the central San Juan Basin, the Dakota Sandstone and Mancos Shale entered the oil generation window in the Eocene and were elevated to temperatures appropriate for the generation of dry gas by the late Oligocene. Along the southern margin of the central basin, the Dakota and lower Mancos entered the thermal zone of oil generation during the late Miocene (Huffman, 1987). It is not known at what point hydrodynamic forces reached sufficient strength to act as a trapping mechanism, but the early Miocene time is likely for the establishment of the present-day uplift and erosion pattern throughout most of the basin. Migration of the oil in the Dakota was still taking place in the late Miocene, of even more recently, in the southern part of the San Juan Basin.

Traps: The Dakota gas accumulation in the central basin is on the flanks and bottom of a large depression and is not localized by structural trapping (Fig. UM-46). The fluid transmissibility characteristics of Dakota sandstones are generally consistent from the central basin to the outcrop. Hydrodynamic forces, acting in a basinward direction, have been suggested as the trapping mechanism, but these forces are still poorly understood. The seal is commonly provided by either marine shale or paludal carbonaceous shale and coal. Production is primarily at depths ranging from 6,500 to 7,500 feet.

Exploration status and resource potential: The Dakota discovery well in the central basin was drilled in 1947 southeast of Farmington, New Mexico. The Dakota Basin Field, containing the Dakota gas pool, was formed February 1, 1961, by combining several existing fields. By the end of 1993 it had produced over 4.0 TCFG and 38 MMB condensate. Almost all of the Dakota interval in the central part of the basin is saturated with gas, and additional future gas discoveries within the central basin field and around its margins are possible.

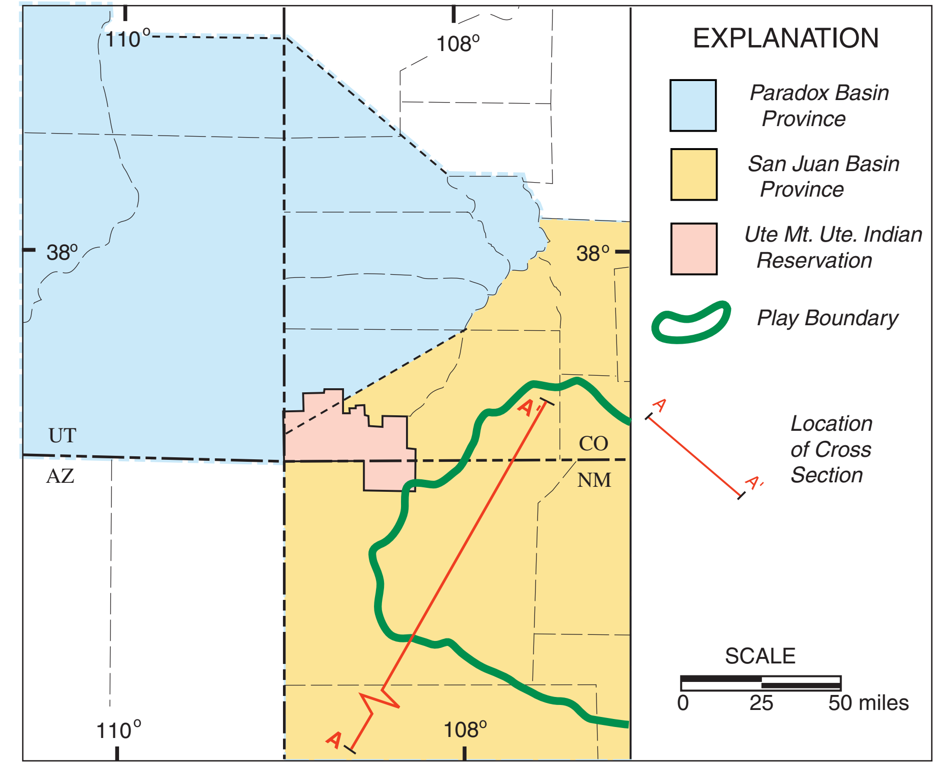


Figure UM-45. Location of Dakota Central Basin Gas Play (modified after Gautier, et al., 1996).

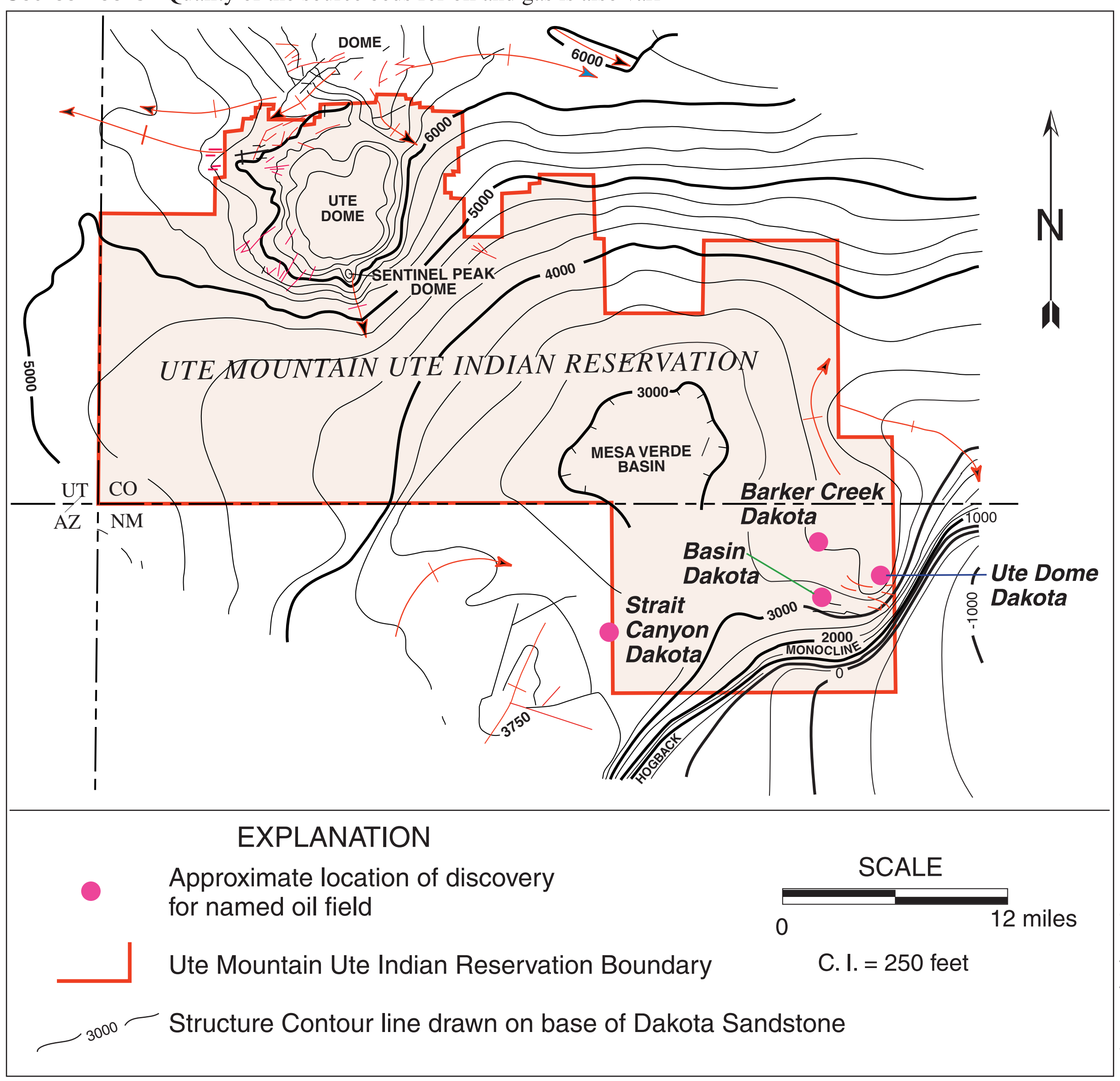


Figure UM-46. Structure contour map of the Dakota Formation and location of the discovery wells for fields in and near the reservation (modified after Anderson, 1995).

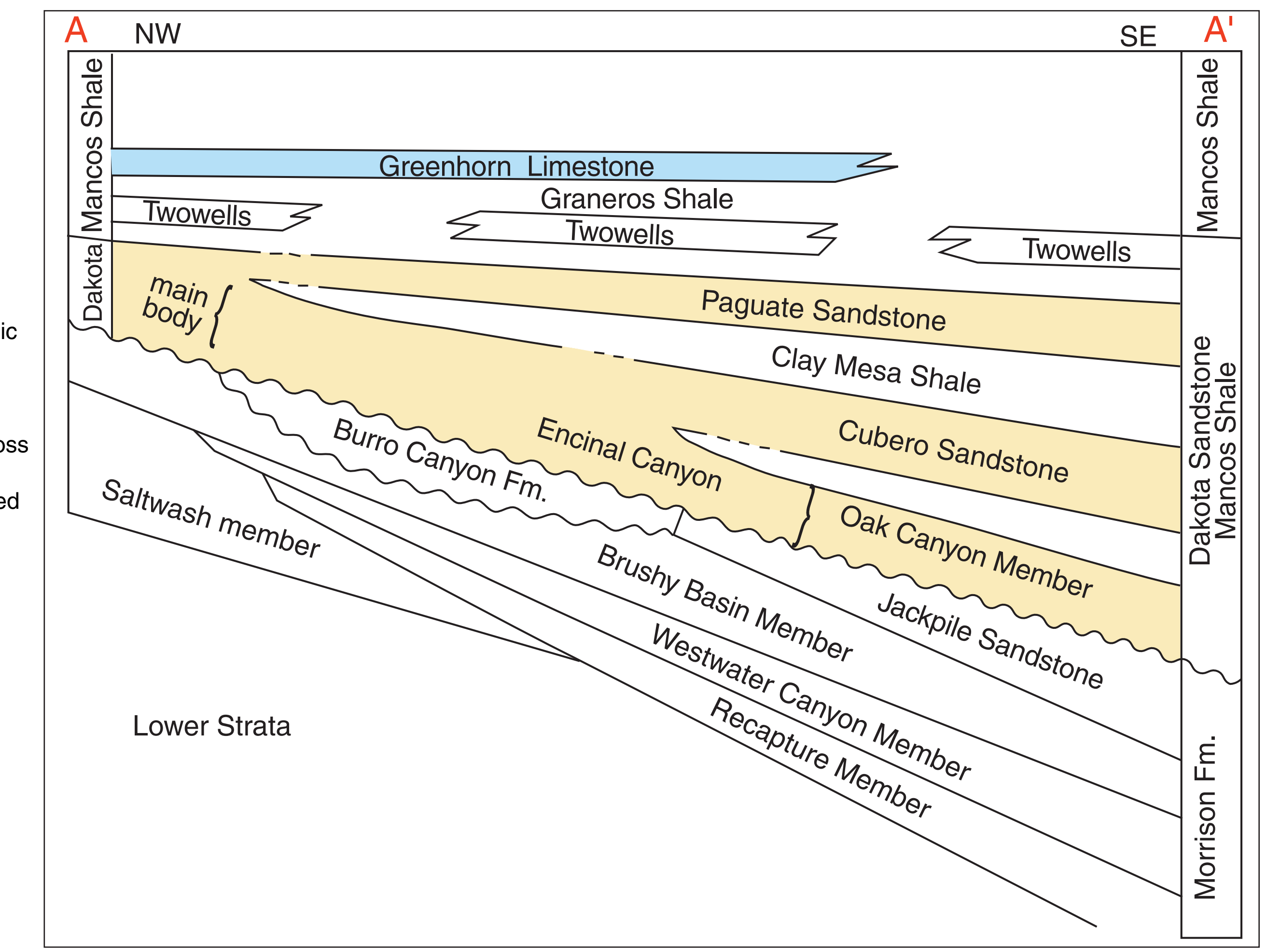


Figure UM-47. Schematic stratigraphic cross section of Cretaceous- Jurassic rocks in the San Juan Basin. Location of cross section is labeled on Figure UM-45 (modified after Walters, et. al., 1987).

Analog Fields in and near Reservation

(*) denotes field lies inside Reservation boundaries

*Barker Creek Dakota

(Fig. UM-48)

Location of discovery well: se ne 16 - T32N - R14W (1925)
Producing formation: Upper Cretaceous Dakota Sandstone, Paradox Formation
Number of producing wells: 5 (1977)
Production: 215,279,080 MCFG (1996)
Gas characteristics: Sweet gas
Type of drive: Gas expansion
Average net pay: 40 feet
Porosity: 14%
Permeability: 0 - 1500 md, average = 16.5 md

*Ute Dome Dakota

Location of discovery well: se 35 - T32N - R14W (1921)
Producing formation: Cretaceous Dakota Sandstone, Paradox Formation
Number of producing wells: 14 (1977)
Production: 93,589,058 MCFG (1996)
Type of drive: Combination water drive and volumetric
Average net pay: 30 feet
Porosity: 15%
Permeability: 10 md

*Basin Dakota

Location of discovery well: ne nw 4 - T27N - R10W NMPM (April 1947)
Producing formation: Cretaceous Dakota Sandstone
Number of producing wells: 2395
Production: Gas: 2,753,610,459 MCFG
Oil: 27,186,314 BO
Characteristics: Gas: 1100 BTU
Oil: 50 ° API Gravity
Type of drive: Gas expansion (upper part), Water drive (lower part)
Average net pay: 50-70 feet
Porosity: 5-15%
Permeability: 0.1 - 0.25 md

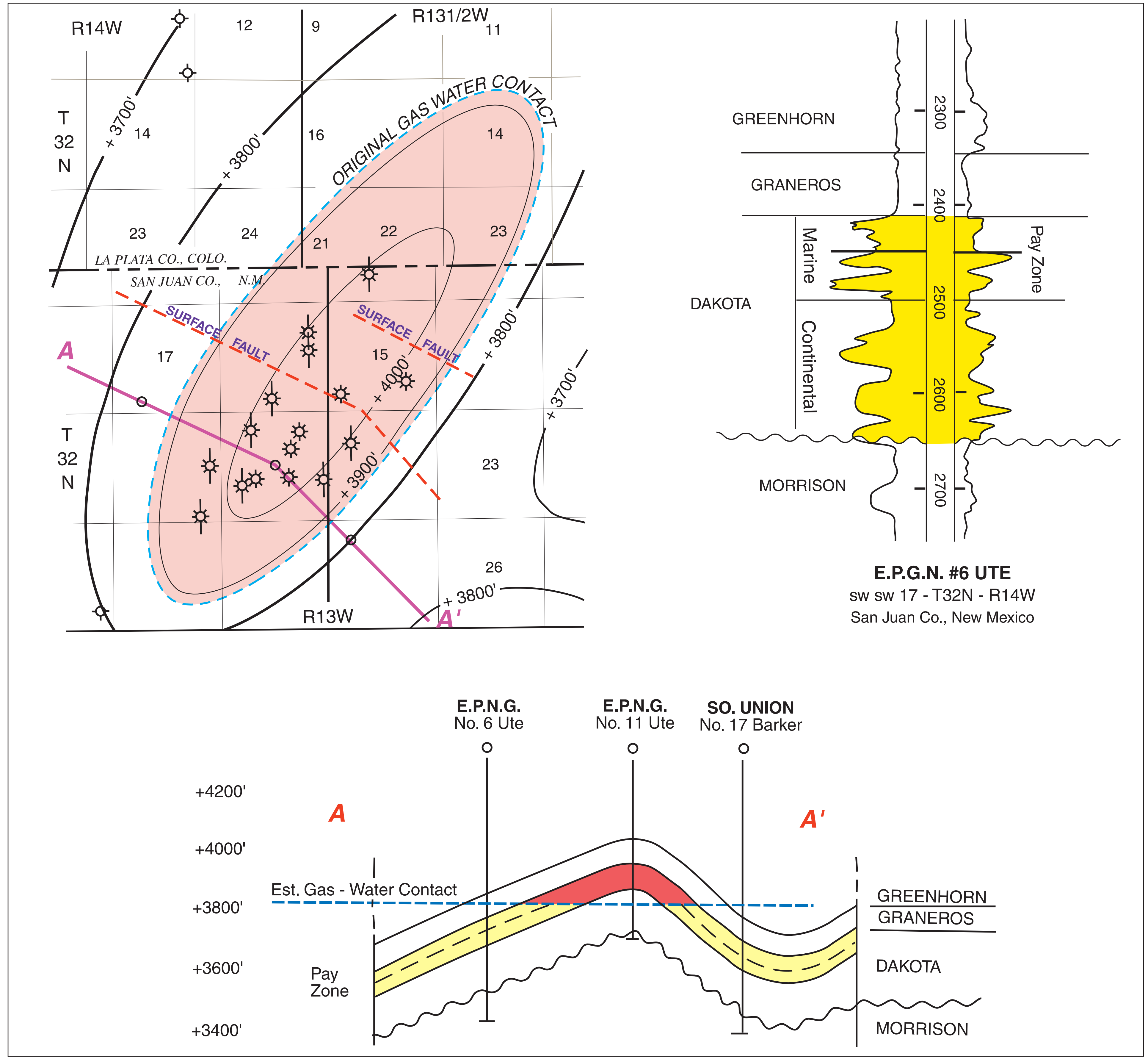


Figure UM-48. Structure contour map of the top of the Graneros Shale, cross section, and type log for the Barker Creek Dakota Field (modified after Matheny, 1978)

Buried Fault Blocks, Older Paleozoic Play

(USGS Designation 2101)

General Characteristics

The play is based on the occurrence of oil accumulations in fault blocks involving pre-Pennsylvanian rocks, mainly in the salt anticline area of the Paradox Basin, and it covers an area of approximately 7,500 square miles (Fig. UM-49). Most of the structures are associated with the salt anticlines themselves and were growing at the same time that the salt was moving.

Reservoirs: Reservoirs are in porous dolomite or dolomitic limestone beds of the Mississippian Leadville Limestone (Figs. UM-50, -52, and -53) and the Upper Devonian McCracken Sandstone Member (Figs. UM-51 and -53) of the Elbert Formation. Reservoirs are as thick as 200 feet, and porosity varies from 5 to as high as 25% in local cases. Permeability is generally low, but is as much as several hundred mD in places.

Source Rocks: Probable source rocks are the organic-rich black dolomitic shales of the Pennsylvanian Paradox Formation. Migration into Leadville or McCracken reservoirs occurred where fault blocks are in structural and (or) depositional contact with the black shale, which is commonly highly fractured.

Timing and Migration: Hydrocarbon generation began as early as Permian time and has continued to the present in some cases. Migration into pre-salt reservoirs was probably contemporaneous with the growth of salt structures. Migration pathways were enhanced by severe fracturing of interbedded organic-rich shale during salt movement.

Traps: Known traps are on uplifted fault blocks adjacent to salt anticlines or swells. Seals are Paradox Formation evaporite beds that overlie, or are in fault contact with, Mississippian or Devonian reservoirs. Drilling depths range from 7,000-8,000 feet at the Lisbon field, and to greater than 10,000 feet in other areas.

Exploration Status and Resource Potential: Six oil and gas accumulations produce from pre-salt structural blocks. The largest of these is the Lisbon field, which is approximately 43 MMBO and 250 BCFG in size. The remainder of the fields are noncommercial or marginally commercial. The play is only moderately explored with respect to smaller structures. Future potential is low to moderate, and based on previous production history, undiscovered fields are estimated to be small to medium in size and have minimal oil columns.

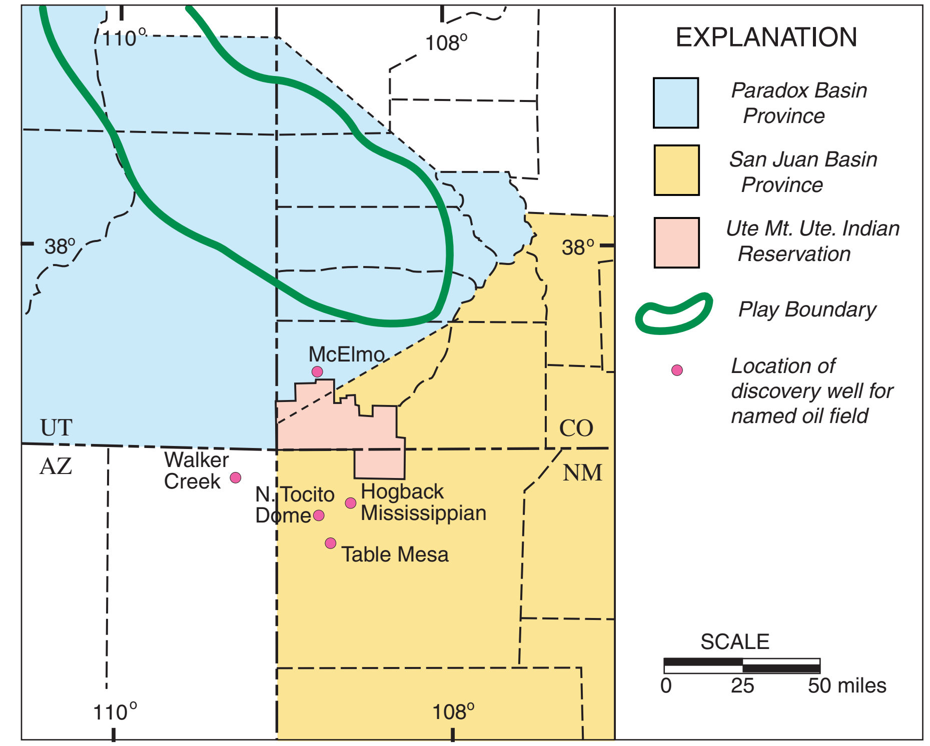
Characteristics of the Buried Fault Blocks, Older Paleozoic Play

In the Ute Mountain Ute Indian Reservation, the Buried Fault Blocks, Older Paleozoic Play consists of the Mississippian Leadville Limestone and the Devonian McCracken Sandstone Member of the Elbert Formation.

The McCracken Sandstone (Figs. UM-51 and -53) is mainly a dolomitic sandstone, sandy dolomite, and dolomitic mudstone. Cyclical fluctuations in relative sea level during McCracken time produced three coarsening-and thickening-upward intervals (parasequence sets) which correspond to the main reservoir units. Depositional environments range from intertidal-supratidal carbonate flat to siliciclastic prodelta and delta front. Reservoir flow units are strongly dominated by siliciclastic lithofacies, whereas carbonate lithofacies compose major flow barriers and baffles.

The Leadville Limestone (Figs. UM-50, -52, and -53) is Kinderhookian to Osagean in age and rests on top of shaly limestones of the Ouray Limestone. The Leadville is capped by a major unconformity which has truncated the formation. Two well defined intraformational markers exist in the Leadville (Fig. UM-57). They are interpreted as major erosional channels caused by upward shoaling cycles that include a full suite of environments ranging from shallow marine tidal shelf through lagoonal and supratidal. The markers represent time stratigraphic lines which form the boundaries between depositional units and separate facies of the Leadville. The Leadville has undergone complex diagenesis. Moldic porosity and vuggy porosity are common.

Figure UM-49. Location of Buried Fault Blocks, Older Paleozoic Play and location of oil and gas discovery wells for named fields (modified after Peterson, 1996).



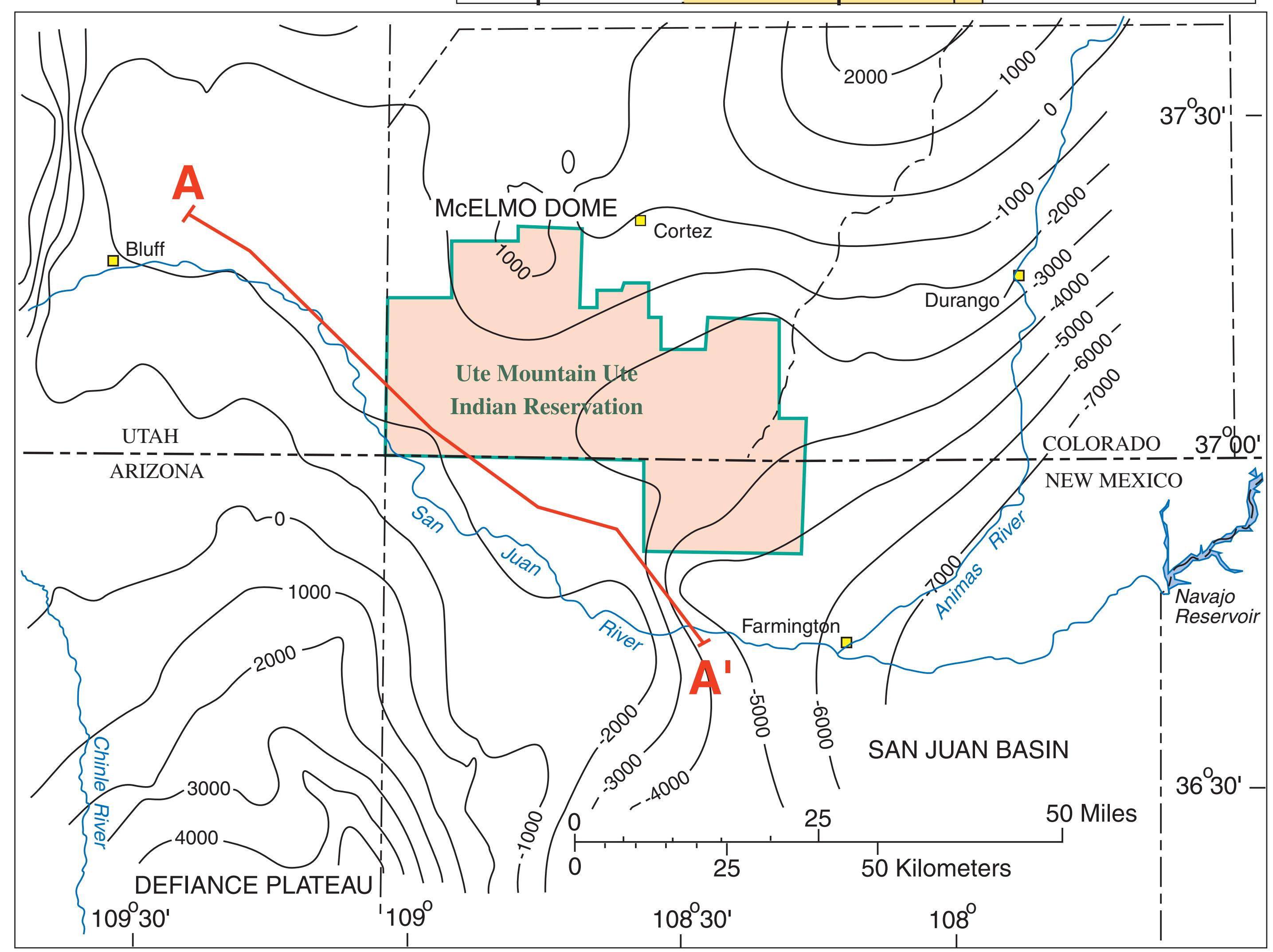


Figure UM-50. Structure Contour Map of the top of the Mississippian Leadville Limestone and location of cross section in figure UM-53 (modified from Condon, 1995).

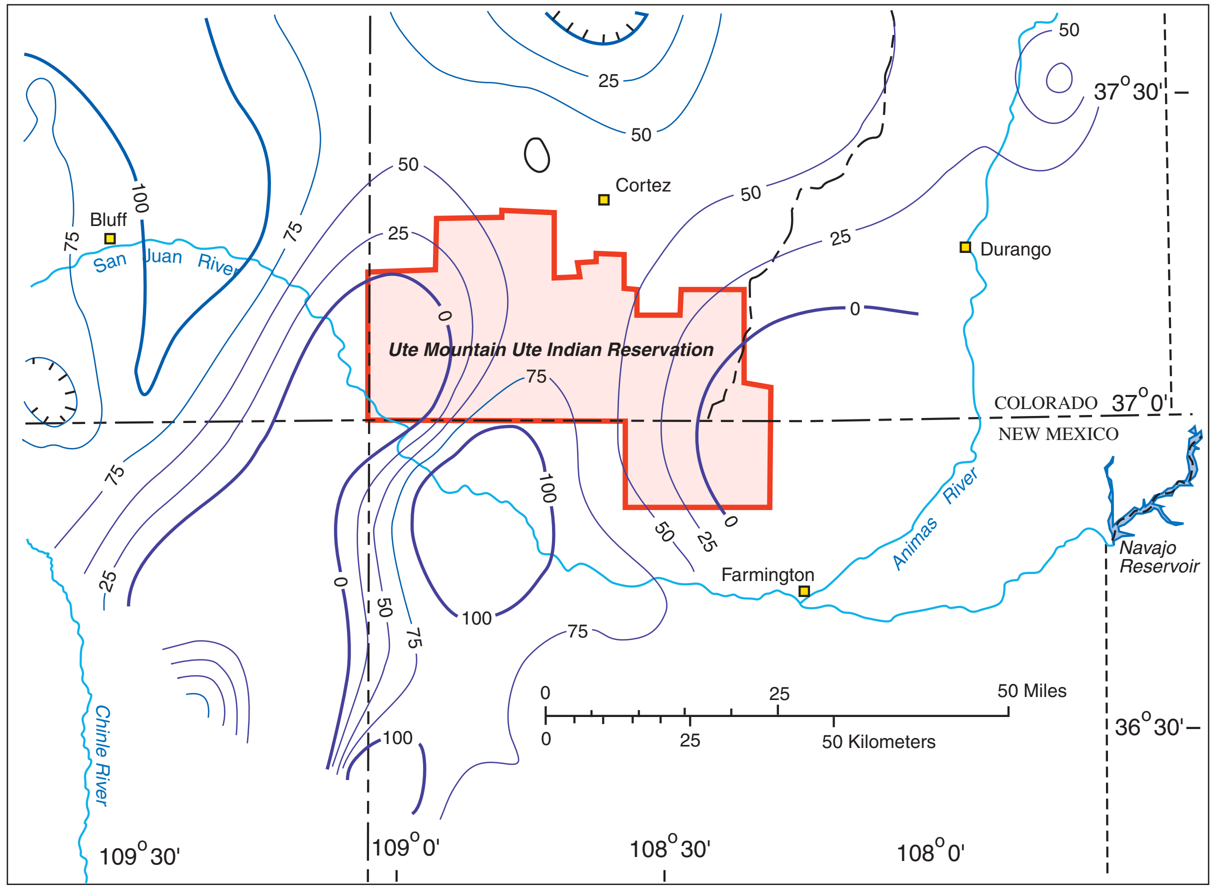


Figure UM-51. Isopach map of the McCracken Sandstone Member of the Elbert Formation. Contour intervals are 25 ft (modified from Condon, 1995).

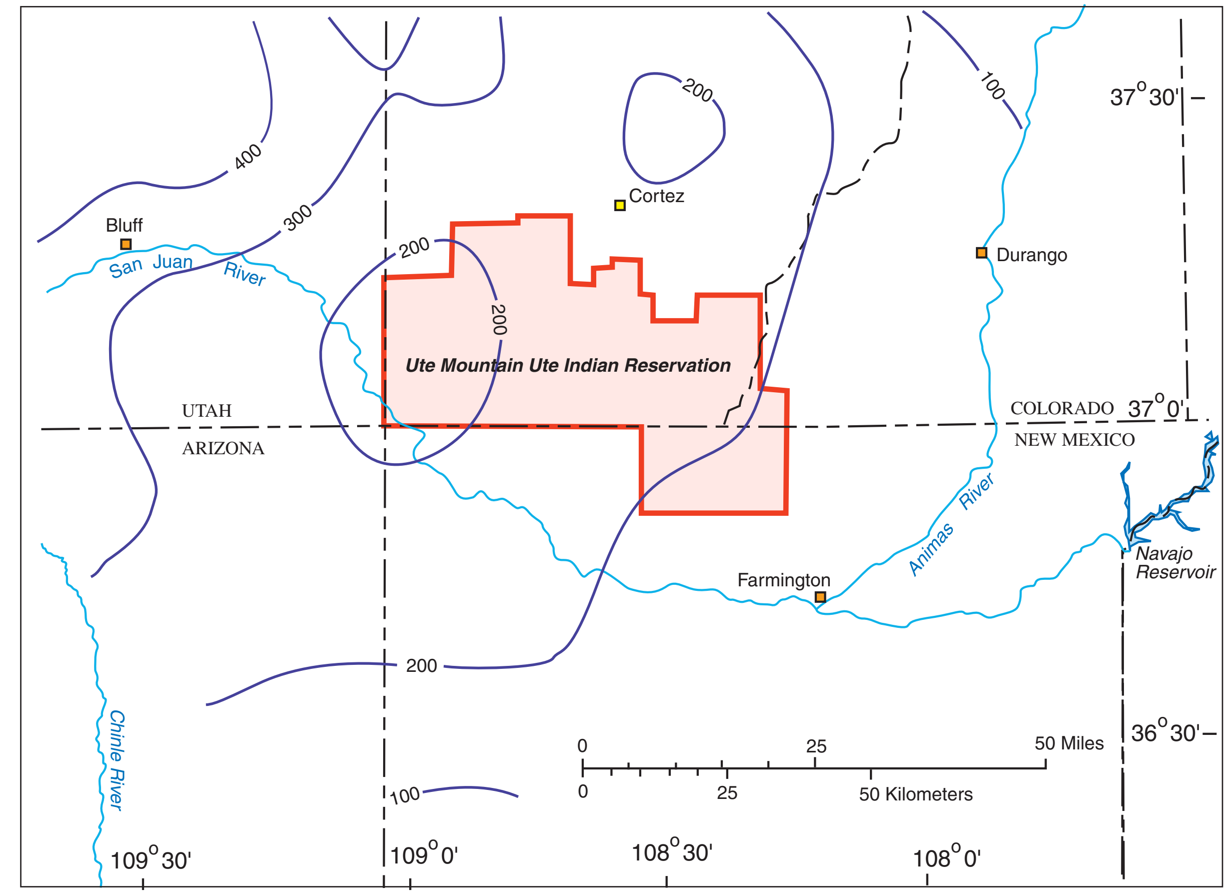


Figure UM-52. Isopach map of the Mississippian Leadville Limestone. Contour intervals are 100 ft (modified from Condon, 1995).

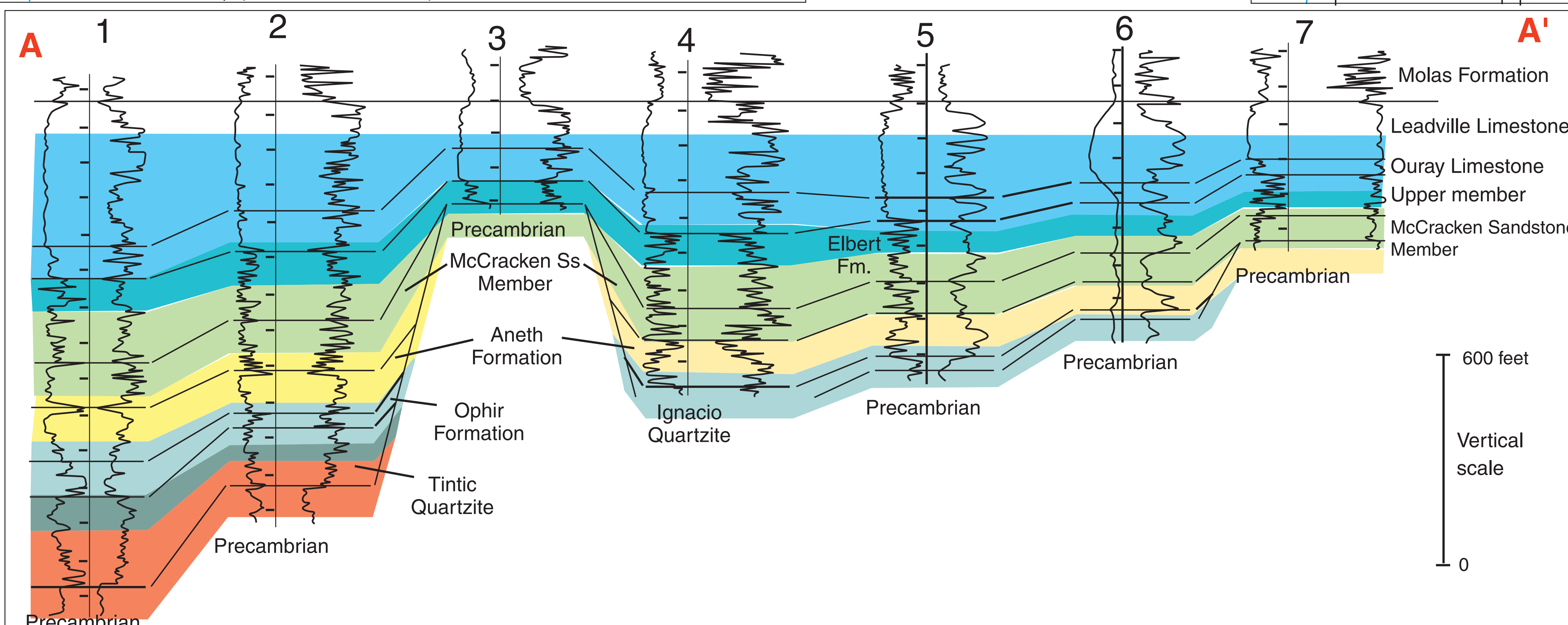


Figure UM-53. Stratigraphic section of Pre-Pennsylvanian units in the Ute Mountain Ute Indian Reservation and surrounding area. All logs are gamma ray-neutron, except for log number 6 which consists of a spontaneous-potential and resistivity curves. Horizontal scale is variable (modified from Condon, 1995).

Analog Field Near Reservation

Lisbon Field

(Figs. UM-54 - UM-57)

Location of discovery well: nw ne ne, sec. 10, T30S, R24E (1959)

Producing formation: McCracken Sandstone Member of the Elbert Formation, Leadville Limestone

Number of producing wells: 11

Production:	1.465 BCFG, <1 MMBO McCracken (1996)
	60 MMBO Leadville (1996)
Oil characteristics:	44 API
Average net pay:	39.4 Feet
Porosity:	0.3 - 16.9%
Permeability:	<0.01 - 272 mD

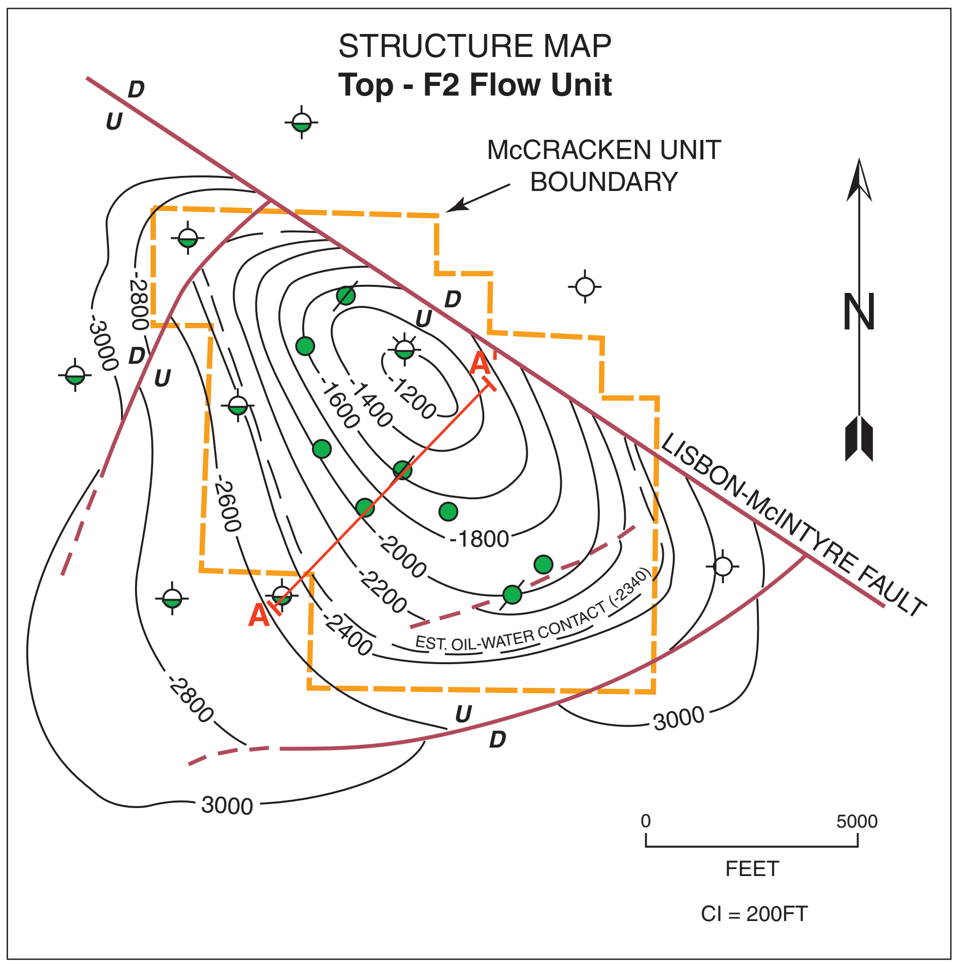


Figure UM-54. Structure contour map of the top of the F2 flow unit for Lisbon field and location of cross section in Figure UM- 55 (modified after Cole and Moore, 1996).

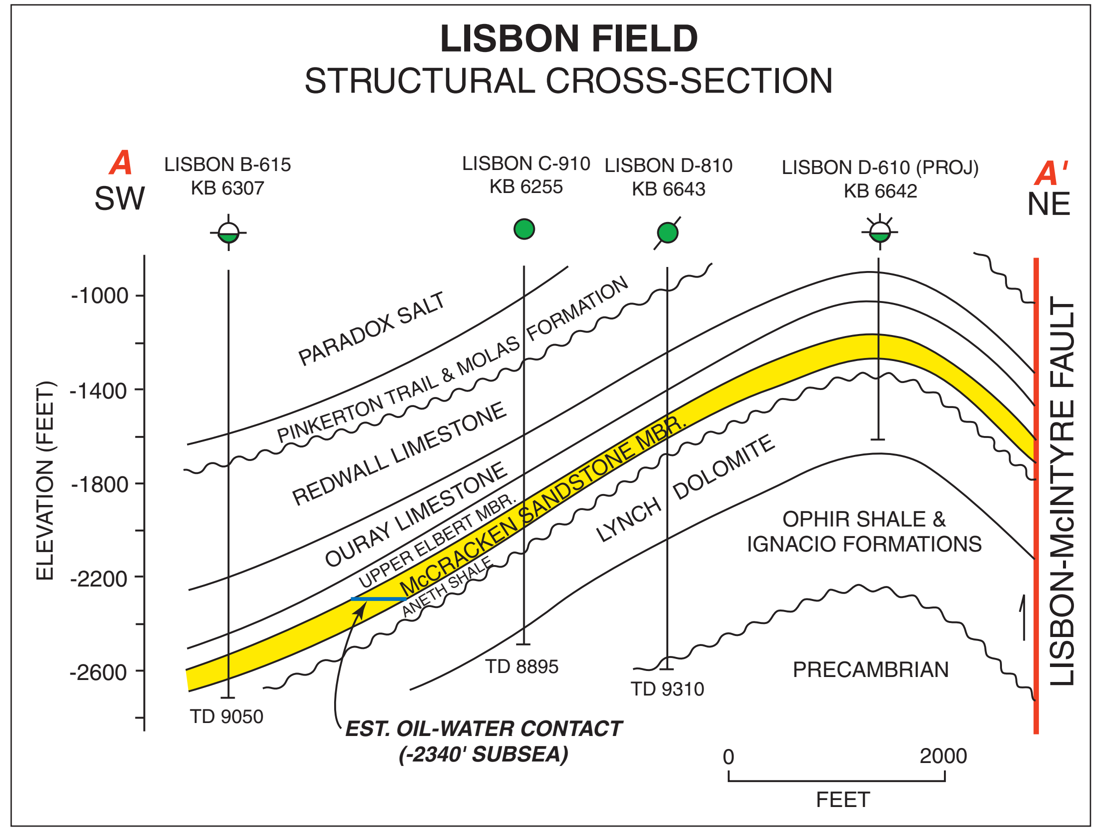


Figure UM-55. Structure cross-section of Lisbon field (after Cole and Moore, 1996).

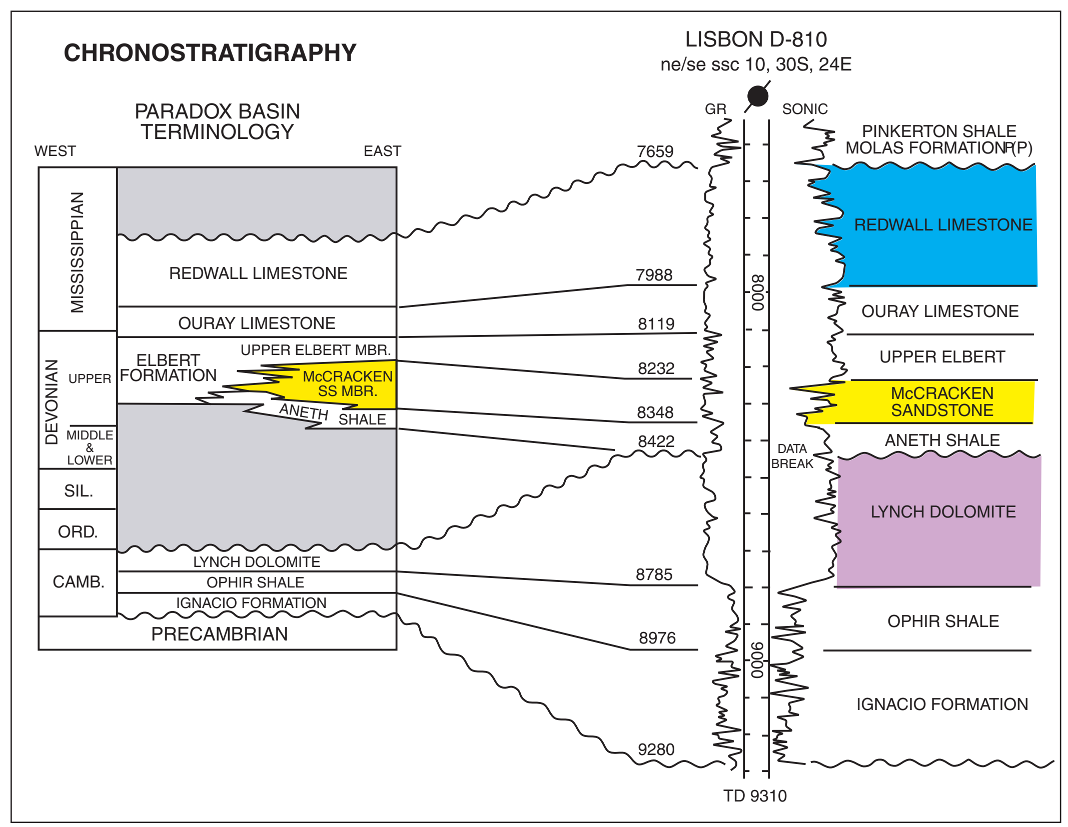


Figure UM-56. Type log for McCracken unit at Lisbon Field (modified after Cole and Moore, 1996).

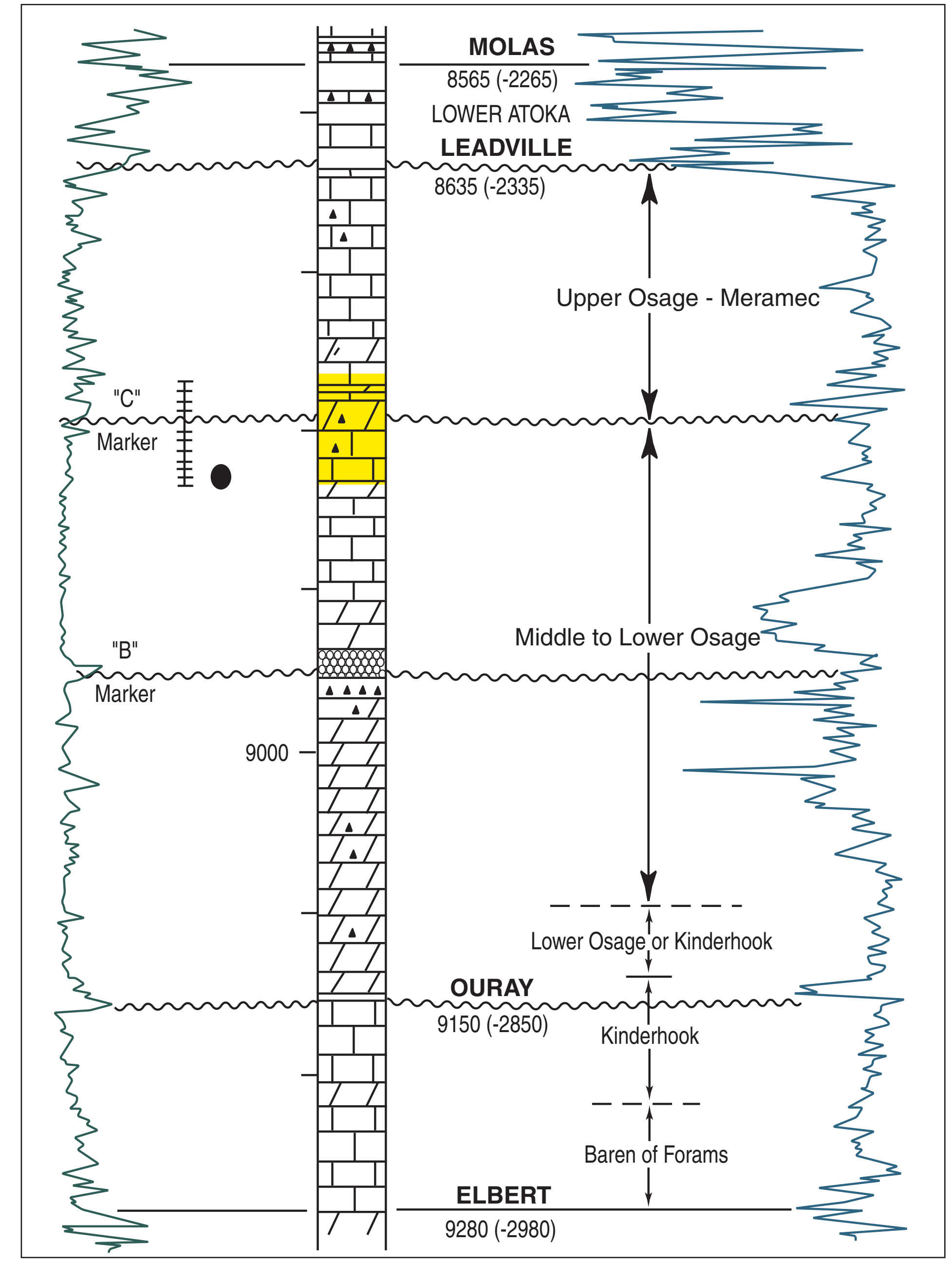


Figure UM-57. Type log for Leadville Limestone unit at Lisbon Field (modified after Fouret, 1996).

Fractured Interbed Play

(USGS Designation 2103)

General Characteristics

This unconventional continuous-type oil and gas play is oil prone throughout most of the Paradox Basin but is more gas prone to the east close to the ancestral Uncompahgre uplift (Fig. UM-58). The reasons for this change in character are increased depth of burial and percentage of terrestrial organics to the east.

Reservoirs: The play depends on extensive fracturing in the organ ic-rich dolomitic shale and mudstone in the interbeds between evap orites of the Pennsylvanian Paradox Formation or carbonate and clastic rocks of the related cycles on the shelf of the Paradox evapor ite basin. These shales and mudstones may be as thick as 130 feet but are more commonly less than 20 feet thick.

Source rocks: These organic-rich black dolomitic shales and mud stones are the source rocks for most, if not all, of the oil and gas in the Paradox Basin. Total organic carbon commonly ranges from 1 to 5% but may be as high as 20%. Oil produced by these source rocks typically has 40°-43° API gravity and low sulfur content.

Timing and migration: The thermal history of these rich source rocks is determined mostly by depth of burial and to a lesser degree by the added effect of the Oligocene volcanic activity. Pennsylvani an, Permian, Late Cretaceous, and early Tertiary sediments thicken significantly to the east so that the Pennsylvanian section entered the thermal zone of oil and gas generation at different times depending on location. Close to the Uncompahgre Uplift, Pennsylvanian rocks may have generated oil as early as the Permian; elsewhere these rocks may have entered the oil generation zone in the Late Creta ceous and the dry gas zone as late as the Oligocene.

Traps: Fracturing of the shale on structures is a necessary attribute of this play, but the actual trapping and sealing mechanisms may be stratigraphic as well as structural because the fractures die out into unfractured shale. Only certain intervals within the total shale thick ness may be of sufficient richness or be sufficiently fractured for significant oil production. Depths to potential targets vary greatly from more than 15,000 feet near the eastern basin margin to less than 5,000 feet on the Four Corners Platform.

Exploration status and resource potential: Until recently, the on ly significant production from this play was from the Cane Creek Shale in the Lone Canyon field discovered in 1962. Recently, near by Bartlett Flat field has been developed by directional drilling in the Cane Creek Shale at a depth of approximately 9,000 feet. The Cane Creek, Chimney Rock, Gothic, and Hovenweep Shales have the most potential due to both organic content and thickness.

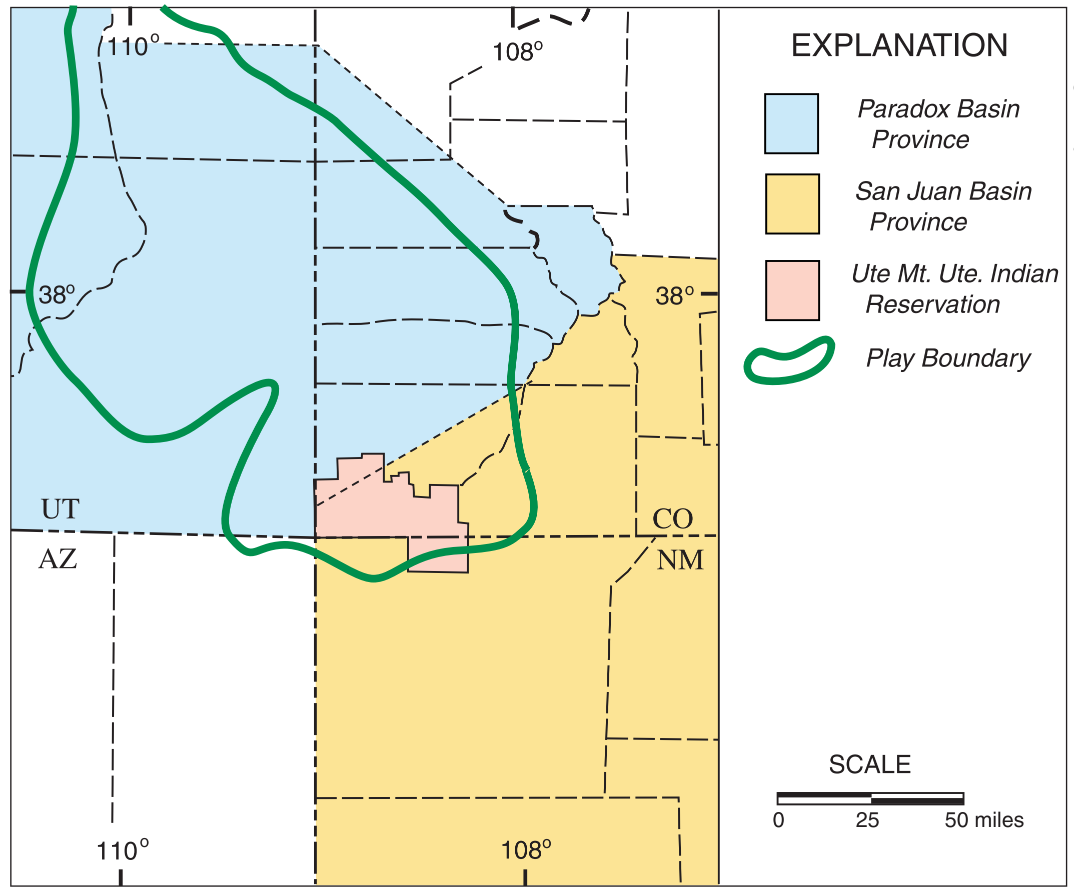


Figure UM-58. Location of Fractured Interbed Play (modified after Gautier, et al., 1996).

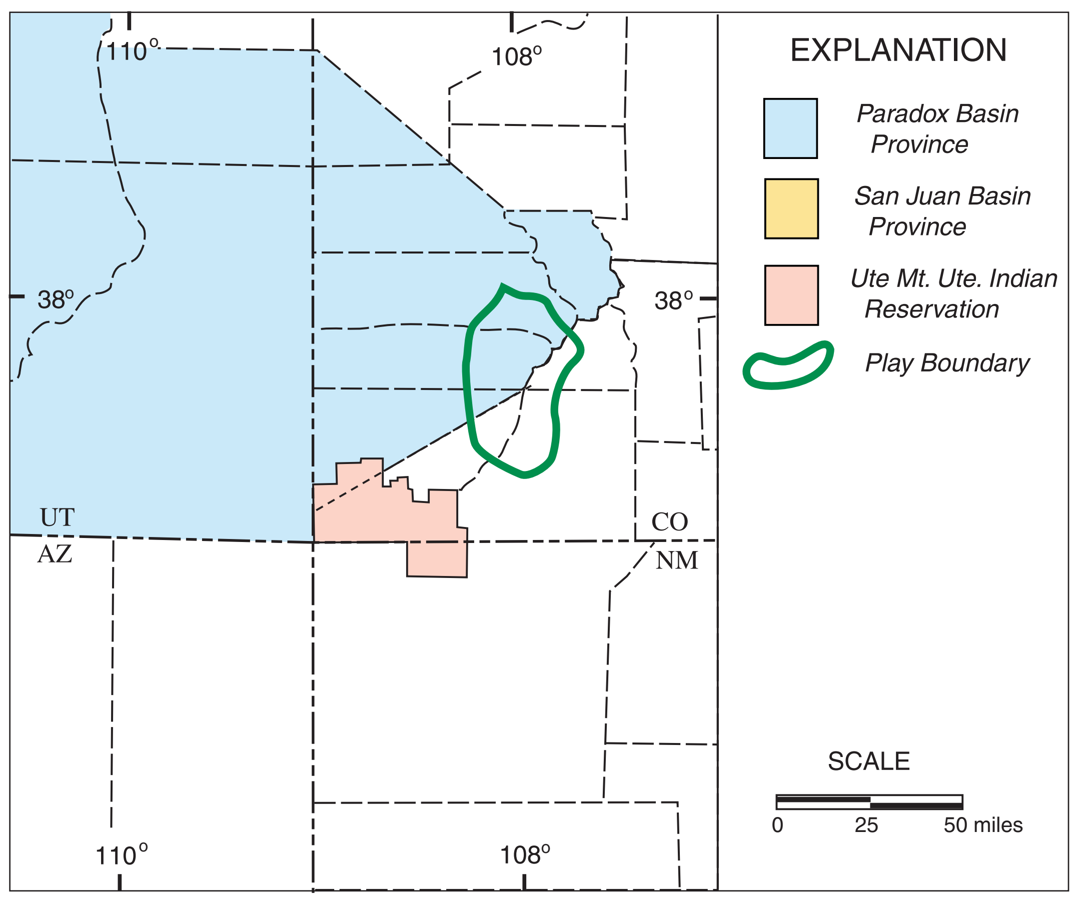


Figure UM-59. Location of Permian-Pennsylvnian Marginal Clastics Gas Play (modified after Gautier, et al., 1996).

Permian-Pennsylvanian Marginal Clastics Gas Play

(USGS Designation 2104)

General Characteristics

This hypothetical play, formerly known as the Silverton Delta Play (Peterson, 1989), has been renamed to more accurately reflect the ge ometry and depositional environment of the reservoir rocks. The Sil verton fan delta is limited to an area near the Colorado-Utah state line, but marginal clastic rocks extend the length of the ancestral Un compahgre Uplift (Fig. UM-59). These clastics were deposited as co alesced outwash fans that intertongue with the cyclic marine deposits of the Pennsylvanian Hermosa Group.

Reservoirs: Gas shows have been encountered in porous and perme able sandstone intervals within the generally arkosic Permian Cutler Formation in the vicinity of the ancestral Uncompahgre Uplift. Such potential reservoir rock is present where feldspar and clay were winn owed out by wave action or fluvial stream flow. For most of the area, the lower part of the Pennsylvanian interval is more likely to contain these beds than the upper part because of the lower original feldspar content of the lower part. In the upper part of the Pennsylvanian in terval, the southeastern Paradox Basin province is more likely to con tain such beds because of the presence of a large fan delta complex that provided the necessary depositional environments to clean the sandstone.

Source rocks: This play is dependent on the presence of Desmoinesian, organic-rich, dolomitic shale and mudstone in contact or close prox imity to reservoir lithologies. Because this juxtaposition is necessari ly close to the ancestral Uncompahgre Uplift, the play is gas prone due to the preponderance of Type III kerogen from the uplift, as well as the depth of burial in the deep trough along the basin margin.

Traps: Trap types are expected to be dominantly combinations of updip pinchouts of permeable sandstone lenses localized on folded and faulted structures. Seals are provided by shale beds as well as by reduced permeability due to clay.

Exploration status and resource potential: Little exploration has taken place within this play and there is no production to date, but shows have been reported from Permian Cutler sandstone bodies. The presence of excellent source rocks and structures are factors in its fa vor.